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A Simulation Study of Horizontal, High-Angle, and Vertical Wells in Eastern Devonian Shale

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ABSTRACT

This study is a comparative evaluation of predicted gas production from horizontal, high-angle, and vertical wells in the tight, fractured Devonian shales of West Virginia. The optimal drilling method was determined by economic and production comparisons of simulation results from studies of unstimulated and stimulated wells of the following types: a single horizontal well, a single high-angle well, and up to four vertical wells. Infill drilling was compared to new-lease wells, and the effect of faulting on predicted gas production was studied. The study showed that new-lease horizontal drilling is the optimal method in West Virginia, and high-angle drilling results in a slight improvement over vertical drilling. Horizontal drilling showed as much as a 46 percent improvement in production performance over both vertical and high-angle drilling for new-lease wells. Economically, a single 2,000-ft (6.096×10^2 m) horizontal well revealed a ROR of 40 percent and payout of 1.6 years as compared to 11.2 percent, 4.9 years and 4.1 percent, 7.8 years for single new lease vertical and 60° high-angle wells, respectively.

BACKGROUND

Natural gas production from the Devonian shales of the eastern United States has long been a supplemental source of gas. The first Devonian shale gas well was drilled in 1821 near Fredonia, New York.[1] Wells were drilled in Ohio and West Virginia by 1860. Field development began in the Big Sandy Field of eastern Kentucky in 1914 and has continued in the Appalachian Basin to the present time. Cumulative production from these shales to date is less than 3 Tcf (85×10^9 m^3), and annual production is only 0.1 Tcf (2.8×10^9 m^3).[1] Production from Devonian shale gas wells is relatively high at first (greater than 200 Mcf/d [5.67×10^3 m^3/d]) but declines steadily to a level that remains constant for 10 to 30 years (10 to 50 Mcf/d [283 to 1,416 m^3/d]).[1,2] This is especially true for the Devonian shale wells of West Virginia. Gas production from these naturally fractured wells progresses in stages from high gas production when free gas in the fracture system is released where the system is immediately connected to the wellbore, to low gas production as gas diffuses through the shale matrix and desorption takes place. Gas can exist as free, absorbed gas, in both the matrix and fracture system, and as adsorbed gas in the matrix. Free gas is produced quickly at a high rate, but the adsorbed gas is produced slowly in low volumes. Devonian shale wells may produce for more than 50 years under these conditions.[3]

The Devonian shales of the eastern United States could become a major source of gas. The U.S. Department of Energy (DOE) has been involved in research on determining the recoverable reserves and the technologies needed to produce this resource. Estimated gas in place reserves range from 225 to 1,861 Tcf (6.37×10^{12} to 52.7×10^{12} m^3), for the entire Appalachian Basin, including West Virginia, Kentucky, and Ohio. West Virginia alone has an estimated 69 Tcf (1.95×10^{12} m^3) in recoverable gas of the 135 Tcf (3.82×10^{12} m^3) gas-in-place. In the Appalachian Basin, the Devonian shales consist of strata above the Onondaga Limestone and below the Berea Sandstone, which is Lower Mississippian. These strata vary across the basin from shale in western Ohio to siltstone in central and southeastern West Virginia.[3] This study examines the West Virginia area of the Appalachian Basin, and particularly drilling scenarios in the Beech Fork Field of Calhoun and Roane counties. (See Figure 1.)

INTRODUCTION

As with all development drilling ventures, the goal is to be able to produce the maximum amount of

References and figures at end of paper.

gas in the shortest amount of time and to do this with the lowest investment and highest rate of return. To meet this goal, the most efficient drilling method needs to be determined. How does one do this in areas typical of the Devonian shales with their known sustained low production that continues for 30 to 40 years? An extensive understanding of the regional geology is extremely important to provide a complete reservoir description of the target areas proposed for drilling. Well logs and well reports of previously drilled and newly drilled gas wells in the area are very helpful. Furthermore, understanding the physical, structural, and past production characteristics of the Devonian shales is helpful in determining the best way to contact the largest reservoir area while connecting the natural fractures. The Devonian shale gas reservoirs in West Virginia are very complex with a low permeability matrix and a natural fracture system, resulting in a dual porosity system. (See Figure 2.) Drilling methods that connect the major natural fracture system will have a higher potential for increased gas recovery efficiency. Since most of the natural fractures are vertically oriented in the Devonian shales of West Virginia, horizontal drilling technology would contact more of the gas in the reservoir by crossing (and hence, connecting) the fracture system. This creates the potential for maximum gas production, and of course, more favorable economics. Reservoir simulation of gas production using different drilling methods allows one to predict the optimal method of gas production for this study area. The application of horizontal drilling technology and reservoir simulation in the Wayne County area of West Virginia by DOE/METC has been an active project and has been the subject of several SPE papers.[4,5]

RATIONALE

This study's objective is to show which drilling method will provide the most favorable gas production results in the study area. This is accomplished through comparing infill drilling in areas with existing vertical wells to newly drilled acreage without existing vertical wells. History-matched reservoir parameters were used in the predictive simulations for all cases. Infill drilling with high-angle and horizontal wells was simulated in a fault-zone area peculiar to the Beech Fork Field and in a no fault zone for comparison. Devonian shales are characterized by a predominantly vertical, natural fracture system that transports free and desorbed gas from the fractures and matrix to a wellbore. Therefore, the drilling method that drains the largest reservoir volume, and in this case, effectively connects the vertical natural fracture system, will have the best chance of ultimately producing the highest amount of gas. Vertical wells are limited in the sense that they contact a certain vertical thickness of pay zone, which is less than could be contacted by high-angle or horizontal wellbores. In addition, high-angle and horizontal wellbores have a higher probability of connecting the predominantly vertical, natural fracture system of the shales. (See Figure 3.) Figure 3 shows that a horizontal well of length L primarily drains an ellipsoid, while a conventional well drains a cylindrical volume.[6] Both wells drain a reservoir of height h, but their drainage volumes are different. In addition, other studies have shown horizontal drilling to be most effective in reservoirs having pay zone thicknesses less than 100 ft (30.48 m).[6] Appalachian Devonian shales typically fall into the category of thin pay zones. Therefore, high-angle and horizontal drilling will probably be the most efficient drilling methods in this area.

A single phase, dual-porosity reservoir simulator provided the predictive capabilities needed to determine the level of performance for each drilling method. Specific reservoir parameters were obtained through well log data and history matching of vertical wells in the study area. These parameters were then used in the simulated performances for each of the drilling methods examined. In addition, the simulator was able to account for the process of gas desorption as the reservoir pressure declined. Gas desorption values were determined previously from cores fo Devonian gas shales in the Appalachian Basin. Organic carbon content was used as a basis for developing algorithms that calculate original gas-in-place Modification to the amount of desorbed gas present i any given Devonian shale reservoir may be necessar since the amount of desorbed gas can vary with th specific field. Therefore, several runs of the simulator were made with different gas content values fo this study area in order to match historical production as accurately as possible.

EVALUATION PROCEDURE

The first step in this study was to characteriz the Devonian shale reservoir in the Beech Fork Field This field was chosen as a representative Devonia shale reservoir having recent vertical well completions. Historical gas production from this fiel served as input to the simulator in order to histor match the production and provide reservoir parameter for use in the predictive simulations. The cross section through this study area shown in Figure 4 show the trend of the shale along with depth. The stud area included 35 gas wells with initial productio as recent as January 1985. The majority of these ver tical wells were hydraulically stimulated and a showing hyperbolic decline as shown by a typica well in Figure 5. Costs for vertical wells include stimulation costs.

This area was generally covered by a previou report,[8] which examined the natural gas potential c the Devonian shales of West Virginia. Values fc parameters such as pay thickness have been modifie to reflect current measured data and to provide a accurate history match with actual production data Table 1 lists reservoir parameters that resulted fr the history match for the Beech Fork wells. History matched actual production and simulated production a shown in Figure 6.

For each drilling method studied, the histo matched reservoir parameters were used in the predic tive simulations in order to determine the optima drilling method for the area. A grid pattern w developed for the drilling simulation representing t actual field with 80-acre (3.24×10^5 m^2) spacing f the individual vertical wells. The grid-block patte represented vertical, horizontal, and high-angle well by specifying appropriate blocks as history nodes. side view of the wellbore grid pattern utilized in t 60° high-angle well simulation is shown in Figure The history nodes representing the wellbores we monitored during the simulations in order to measu reservoir performance.

Initially, four vertical wells are producing gas on 320 acres (1.29 x 10^6 m^2). Infill drilling with advanced drilling technology cases (high-angle, horizontal, and stimulated horizontal drilling) occurs in the center of the 320 acres (1.29 x 10^6 m^2). (See Figure 8.) For the simulations that consider a fault zone, the fault zone location is shown in Figure 8.

All cases reflect actual historical gas production from January 1985 until June 1988. After June 1988, all case studies continued to produce from the vertical wells. For infill drilling case one, additional wells were not brought on line. The vertical wells continued to produce until the total time of production reached 10 years. For case two, a 60° high-angle well was brought on line after June 1988 and production continued from the high-angle and vertical wells until the total time of production reached 10 years. Case three examined horizontal drilling with a wellbore of 1,000 ft (3.048 x 10^2 m) in length (HW1000), while case four involved gas production from stimulating the 1,000-ft (3.048 x 10^2 m) horizontal well with one 300-ft (9.144 x 10^1 m) wing-length fracture (HWS1000). Finally, case five examined gas production from a horizontal well with a 2,000-ft (6.096 x 10^2 m) wellbore (HW2000). These wells were brought on line after June 1988 and continued to produce along with the vertical wells until the total time of production reached 10 years. Pay zone thicknesses and all reservoir parameters remained the same for all cases so that production performance differences would then be caused by the drilling method used.

This study highlighted two points in time during the predicted simulations. The gas production rate at the initial on-line time was determined as a way of showing the potential increase expected in gas rate when each of the different wells was brought on line. Higher gas production rates in the initial years of production can have a positive effect on payback times. The other point in time was the resultant cumulative gas production at the end of the 10-year time period. (See Tables 2 through 4). The results for all cases were compared and are graphically presented in Figures 9 through 13.

Cases one through five were simulated twice: in a faulted zone and in a non-faulted zone. Permeability showed the biggest difference from a faulted to a non-faulted reservoir. The fault zone has a notably higher permeability value for kx and ky, which is supported from history matching actual gas production in the faulted area. Additional simulations for the non-faulted reservoir, based on drilling ventures for undeveloped acreage, were run to determine the effectiveness of high-angle and horizontal drilling without interference from vertical wells in the field.

DATA -- RESULTS

Reservoir Simulation -- Infill Drilling -- Fault Zone

The results of the predicted infill drilling simulations in a faulted reservoir are presented in Figures 9 and 10 and Table 2. The value for kz was held at 0.01 md for all cases. Figure 9 presents the predicted annual cumulative gas production for a 10-year period for each of the advanced drilling technology cases, beginning with time zero. Vertical wells are producing during the first 3 years. After 3 years, high-angle or horizontal wells come on line and the vertical wells continue to produce. Figure 10 is an expanded version of Figure 9, starting from the 3-year initial on-line time for the advanced drilling technology cases.

Table 2 lists the predicted initial gas-rate increase of infill drilled wells. This percentage increase in gas rate is an indication of the improvement or effectiveness of the drilling method used as the well comes on line. Also listed in Table 2 is the predicted cumulative gas production over a 10-year time period for each case along with the increase expected over vertical wells. In each case, the amount of gas in place available for production is the same.

Over a long period of time, there is a difference in cumulative production for each case but that difference is not as noteworthy as the initial increase in gas production during the early life of the wells. The results do not favor infill drilling using the advanced drilling technologies in a faulted reservoir. This is supported by the indicated maximum increase of only 3.4 percent (1.03 multiple) in expected production for the fractured, 1,000-ft (3.048 x 10^2 m), horizontal well over the four existing vertical wells. The fault zone in this area has obviously altered the reservoir's characteristics (permeability k_x:k_y = 0.6:0.15 md). Historical well data reveals the initial gas rates for two of the vertical wells in the faulted zone to be 900 Mcf/d (25.49 x 10^3 m^3/d), compared to average initial rates of 100 to 200 Mcf/d (0.283-5.66 x 10^3 m^3/d) for typical Devonian shale vertical wells.

Reservoir Simulation -- Infill Drilling -- No Fault Zone

Figures 11 and 12 and Table 3 show the results simulating advanced drilling technologies in a no-fault zone with reservoir permeabilities more reflective of typical Devonian shales in the Beech Fork Field (permeability k_x:k_y = 0.15:0.04 md). Vertical wells in this area have initial rates of 120 Mcf/d (3.4 x 10^3 m^3/d). The results of the advanced drilling technology cases reveal 1.11, 1.35 and 1.46 multiples of the 10-year cumulative gas production over the four vertical wells for 60° high-angle, fractured 1,000-ft (3.048 x 10^2 m) horizontal, and 2,000-ft (6.096 x 10^2 m) horizontal wells, respectively. Table 3 also shows significantly higher initial on-line gas rates for the horizontal well cases as compared to the fault zone cases of Table 2.

These results show more of the expected trend of increasing gas production with advanced drilling technologies as compared to the fault zone results. All simulation results were based on a pay zone thickness of 38 ft (1.158 x 10^1 m). Simulations run at twice this thickness, 76 ft (2.32 x 10^1 m), resulted in twice the gas production as compared to the 38 ft (1.158 x 10^1 m) simulation.

RESERVOIR SIMULATION -- NEW LEASE WELLS

Figure 13 and Table 4 show the results of new lease drilling for all of the drilling methods on a stand-alone basis with the same reservoir permeabilities as in the non-faulted zone, i.e., k_x:k_y = 0.15:0.14 md. The 10-year cumulative production represents gas production from each case without added production from infill drilling. For the 60° high-angle well, the results show only a 1.10 multiple of production over one vertical well, while the horizontal cases show as high as a 5.65 multiple over a single vertical well. Table 4 also shows higher initial on-line gas rates for the horizontal cases as compared to the same cases on Table 3. The single horizontal well cases with higher predicted gas production than four vertical wells definitely are more attractive than the previous infill drilling cases due to their higher cumulative gas production values and higher producing rates early in the life of the project.

ECONOMIC ANALYSIS

An economic analysis was completed on a before-Federal-tax basis. Predicted gas production from each of the advanced technology cases served as the input production values for subsequent economic analysis. Severance taxes (West Virginia, 6.5 percent) were considered, but advalorem taxes were not included. Initial drilling investments averaged $200,000 for a single vertical well, $600,000 for a single 60° high-angle well, and $800,000 for a single horizontal well. These investments include drilling, completion, and logging costs. Gas price remained at constant dollars ($2.16/Mcf) for the 10-year life of each project. Rate of return (ROR), payout time, and net present value at 15 percent were determined for comparison among the cases.

The added costs for infill drilling with each of the advanced technology cases were incurred after the third year of vertical well production. For the infill-drilling, faulted-zone cases, the approximate 3 percent increase in cumulative production does not warrant the added expense of advanced technology drilling. Table 5 reveals that infill drilling with a horizontal well will reduce project economics instead of the reverse. Comparing the four vertical wells to the horizontal well cases shows a decrease in ROR from 29 percent to 7 percent and a subsequent increase in payout time from 1.9 to 3.8 years. These results are based on uniform reservoir thickness, shape, and extent. Reservoirs having high permeability zones in lenses or pockets at different depths, which are offset from vertical, would favor high-angle drilling. The increased gas production resulting from these lenses could increase revenue to a higher level making the project economics attractive and worthy of the added initial expense.

The new-lease (development well) cases do show an increase in ROR and a decrease in payout time with horizontal drilling. Figures 14 and 15 and Table 5 show that ROR will increase from 11 percent for one vertical well to 40 percent for one horizontal well, with payout times decreasing from 5 to 1.6 years. This decrease in payout time is caused by an increased production in the early years. Thus, there is an increase in cash flow and decrease in the payback time. For the new-lease high-angle well, ROR is not attractive due to the high initial drilling investment ($600,000) and low predicted performance (1.1 multiple of a vertical well). The stimulated 1,000-ft (3.048×10^2 m) horizontal case, HWS1000, was not included in Figure 14 or Table 5.

The infill drilling cases could be made more attractive if pay zone thickness were greater than the 38-ft (1.15×10^1 m) history matched for this area. Production would double in value as the pay zone thickness doubles resulting in higher revenues for the infill drilling cases. The infill drilling investment added to the existing vertical well investment lowers overall project economics as compared to new-lease drilling.

CONCLUSIONS

1. Using advanced technology drilling methods in new-lease areas shows the most promise for attractive economics in the eastern Devonian shales.
2. Horizontal drilling is significantly more effective than 60° high-angle drilling and conventional vertical drilling.
3. Advanced technology infill-drilling methods can be made more economically attractive when Devonian shale pay zones are 70 to 100 ft thick.
4. The presence of a fault zone may significantly reduce the effectiveness of advanced infill-drilling technologies in tight fractured formations due to premature drainage or altered drainage patterns.

NOMENCLATURE

h = Net producing thickness (ft).

k_x = Natural fracture permeability in the x-direction (md).

k_y = Natural fracture permeability in the y-direction (md).

k_z = Natural fracture permeability in the z-direction (md).

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TABLE 1. Reservoir Parameters

Drainage Area (A)	320 acres
Matrix Permeability (k_m)	0.0008 md
Matrix Porosity (ϕ_m)	1.0 percent
Fracture Permeability (k_f)	k_x = 0.6, k_y = 0.15
Fault Zone	k_z = 0.01
No Fault Zone	k_x = 0.15, k_y = 0.04, k_z = 0.01
Fracture Porosity (ϕ_f)	0.09 percent
Fracture Spacing (a)	15 ft
Permeability Anisotropy, ratio	4 : 1 k_x : k_y
Gas Content (G_c)	1.35 scf/ft^3, 50 Mcf/AF
Rock Pressure (P_i)	1,500 psia
Line Pressure (P_l)	50 - 150 psia
Productive Thickness (h)	38 - 40 ft

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TABLE 2. Predicted Results -- Infill Drilling

(Fault Zone)

(Permeability $k_x:k_y$ = 0.60 md:0.15 md)

Gas In Place = 890 MMcf

	10-Yr Cumulative Gas Production (MMcf)	Initial Rate at 3 Yrs (Mcf/day)	Improvement Relative to Vertical Well (Multiples) 10-Yr Production	Improvement Relative to Vertical Well (Multiples) Initial Rate at 3 Yrs
4 Vertical Wells*	702	256	0	0
60° High Angle	707	348	1.007	1.36
Horizontal 1000	721	612	1.027	2.39
Horizontal 1000 (Fractured)	726	852	1.034	3.33
Horizontal 2000	725	938	1.032	3.66

* Production = 4 x single-well production.
Average initial gas production rate = 450 Mcf/day/well
B1 = 0.0002 scf/ft^3/psi

TABLE 3. Predicted Results -- Infill Drilling

(Permeability $k_x:k_y$ = 0.15 md:0.04 md)

Gas In Place = 1,270 MMcf

	10-Yr Cumulative Gas Production (MMcf)	Initial Rate at 3 Yrs (Mcf/day)	Improvement Relative to Vertical Well (Multiples) 10-Yr Production	Improvement Relative to Vertical Well (Multiples) Initial Rate at 3 Yrs
4 Vertical Wells*	693	227	0	0
60° High Angle	774	348	1.12	1.53
Horizontal 1000	920	905	1.33	3.99
Horizontal 1000 (Fractured)	933	1,337	1.35	5.89
Horizontal 2000	1,012	1,548	1.46	6.82

* Production = 4 x single-well production.
Average initial gas production rate = 120 Mcf/day/well
B1 = 0.0009 scf/ft^3/psi

TABLE 4. Predicted Results -- New Lease Wells

(Permeability $k_x:k_y$ = 0.15 md:0.04 md)

Gas In Place = 1270 MMcf

	10-Yr Cumulative Gas Production (MMcf)	Initial Rate at 3 Yrs (Mcf/day)	Improvement Relative to Vertical Well (Multiples) 10-Yr Production	Improvement Relative to Vertical Well (Multiples) Initial Rate at 3 Yrs
1 Vertical Well	173	129	0	0
60° High Angle	333	190	1.92	1.47
4 Vertical Wells*	693	515	4.0	3.99
Horizontal 1000	784	1,043	4.53	8.09
Horizontal 1000 (Fractured)	819	2,292	4.73	17.77
Horizontal 2000	978	2,083	5.65	16.15

* Production = 4 x single-well production.
Average initial gas production rate = 120 Mcf/day/well
B1 = 0.0009 scf/ft^3/psi

TABLE 5. Economic Analysis

ROR (%) -- PAYOUT (yrs) -- NPV $ at 15 percent

	Fault Zone	Infill	New Lease
Vertical	29 % 1.9 yrs (269,818)*	11.2 % 4.9 yrs (10,697)	11.2 % 4.9 yrs (10,697)
60° High-Angle	--	1.6 % 9.0 yrs (298,181)	4.1 % 7.8 yrs -
Horizontal 1000	--	3.7 % 7.8 yrs (253,801)	25.0 % 2.7 yrs 280,147
Horizontal 2000	7 % 3.8 yrs --	5.8 % 6.7 yrs (195,713)	40.0 % 1.6 yrs 558,676

* ( ) denotes negative dollars.

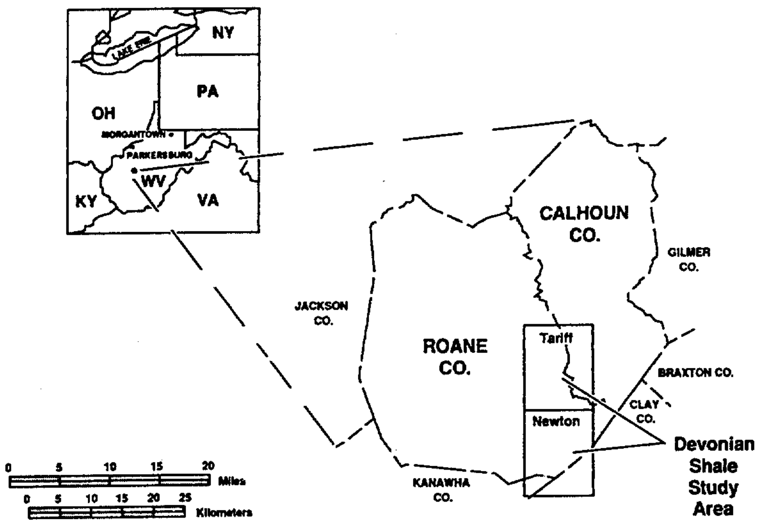

Figure 1. Beech Fork Field Study Area

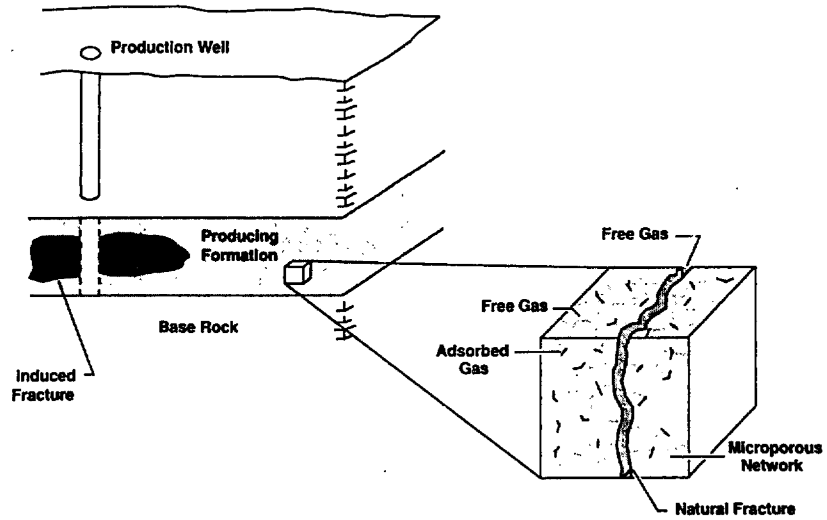

Figure 2. Representation of Dual Porosity Shale Reservoir

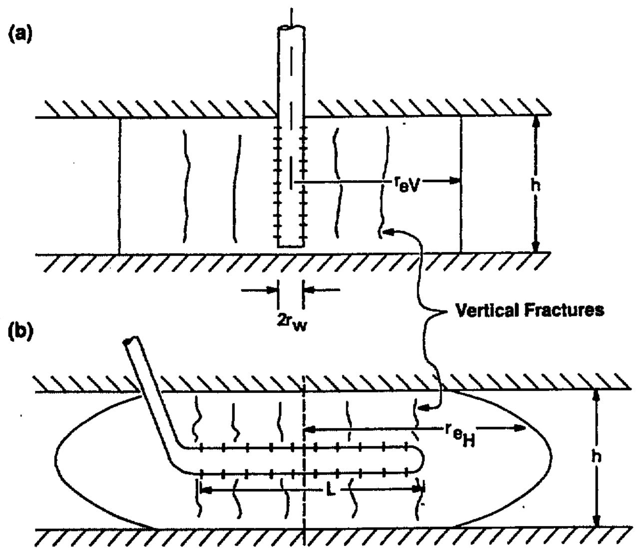

Figure 3. Fractured Vertical- and Horizontal-Well Drainage Volume

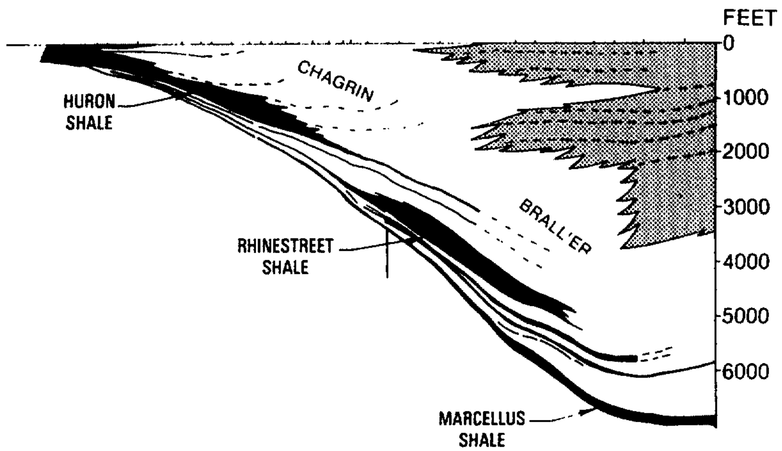

Figure 4 - Devonian Shale Cross Section

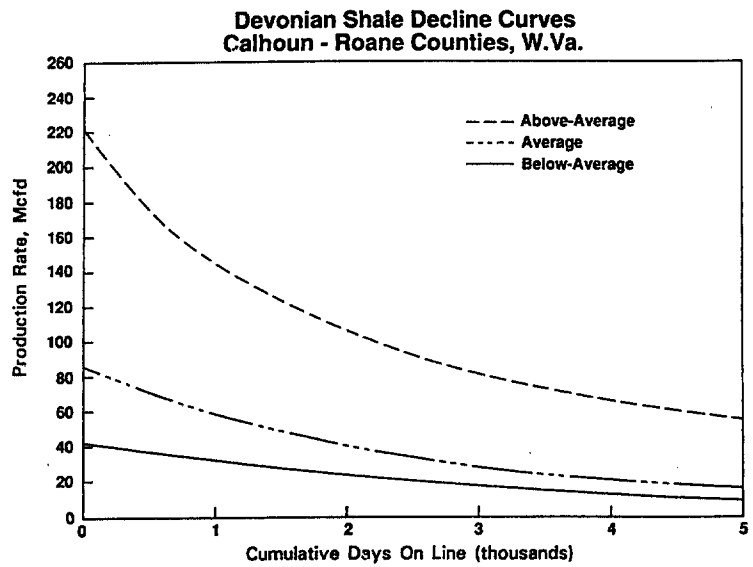

Figure 5 - Typical Devonian Shale Decline Curves

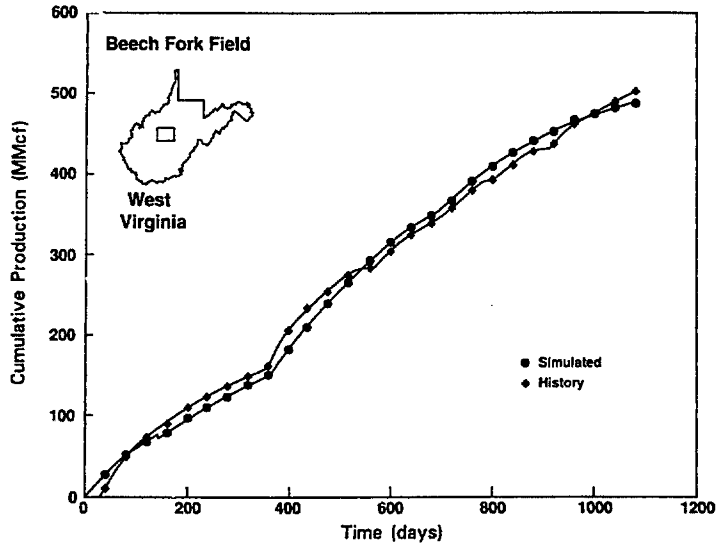

Figure 6. History Match - Gas Production vs. Time

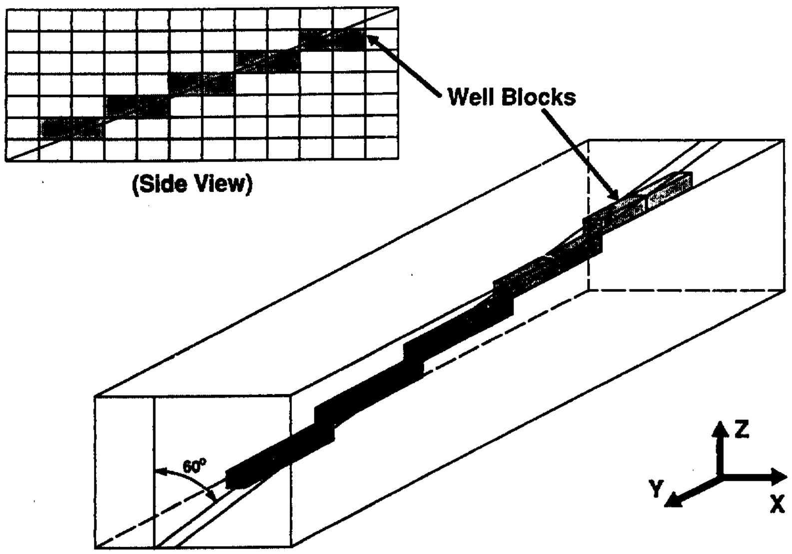

Figure 7 - Wellbore Grid Block Configuration
60° Hi-Angle Well

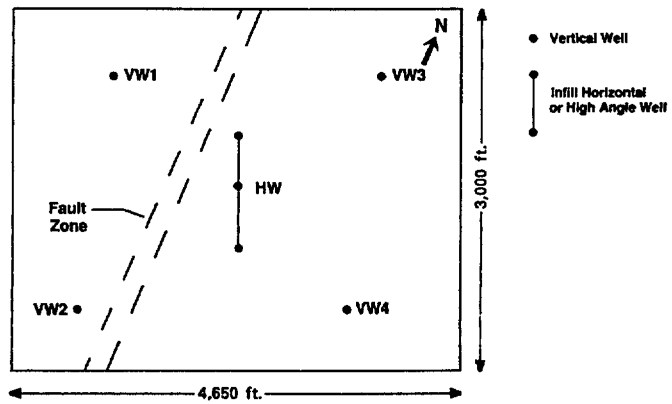

Figure 8. Well Location Map of Infill and Vertical Wells

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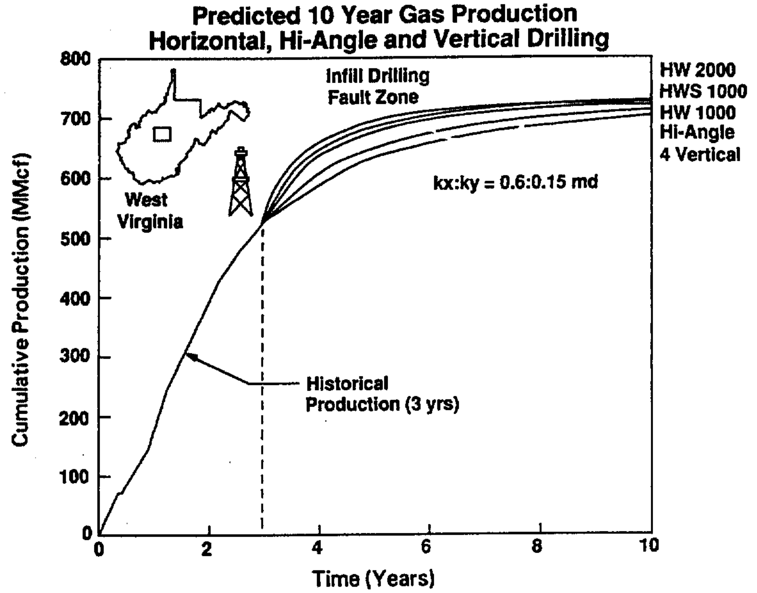

Figure 9 - Predicted Fault Zone Production - Infill Drilling

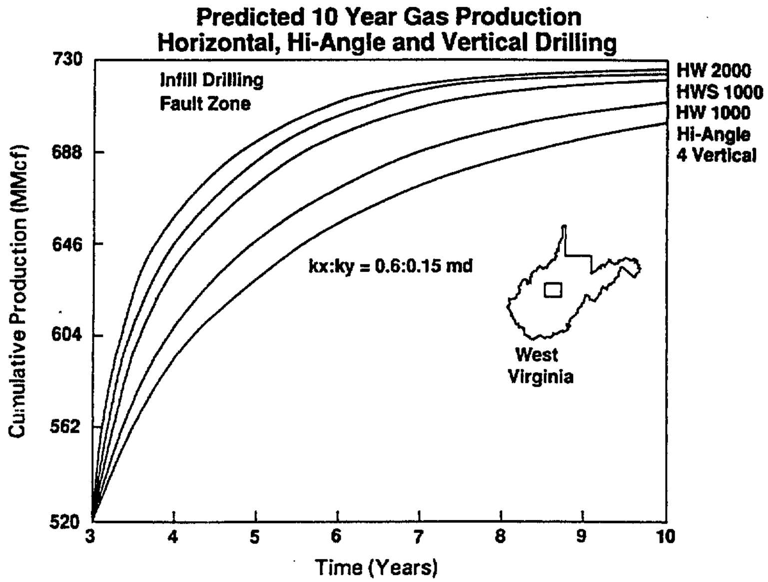

Figure 10 - Expanded Scale of Figure 9

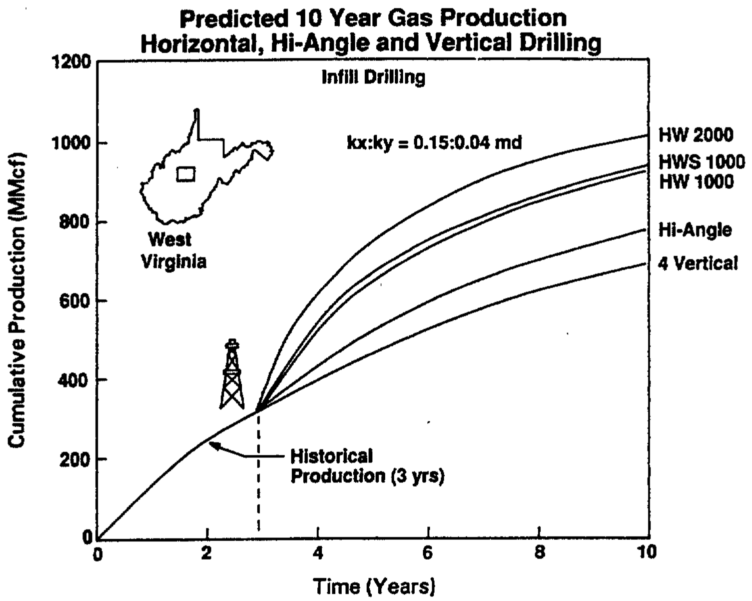

Figure 11 - Predicted Production - Infill Drilling

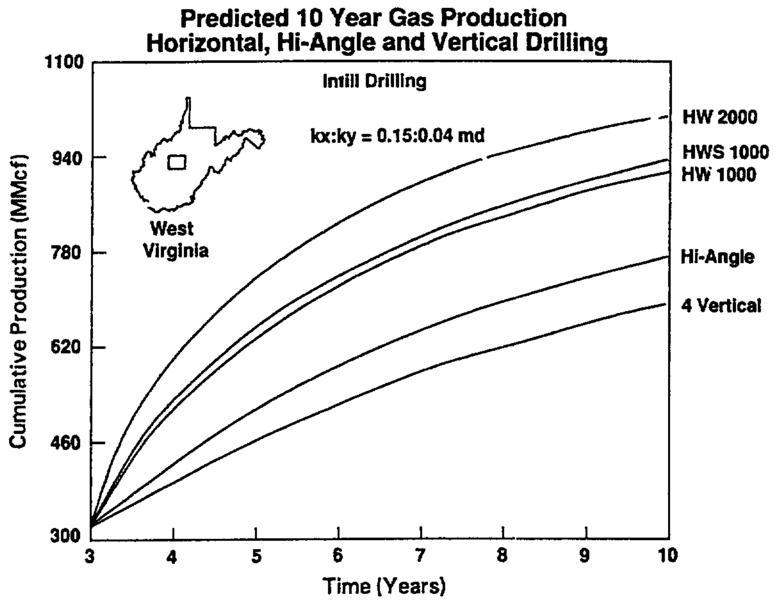

Figure 12 - Expanded Scale of Figure 11

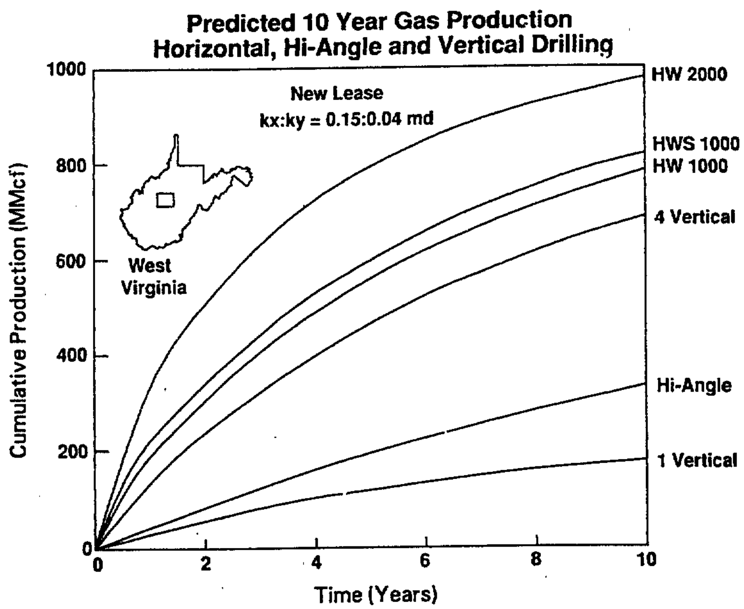

Figure 13 - Predicted Production - New Lease Wells

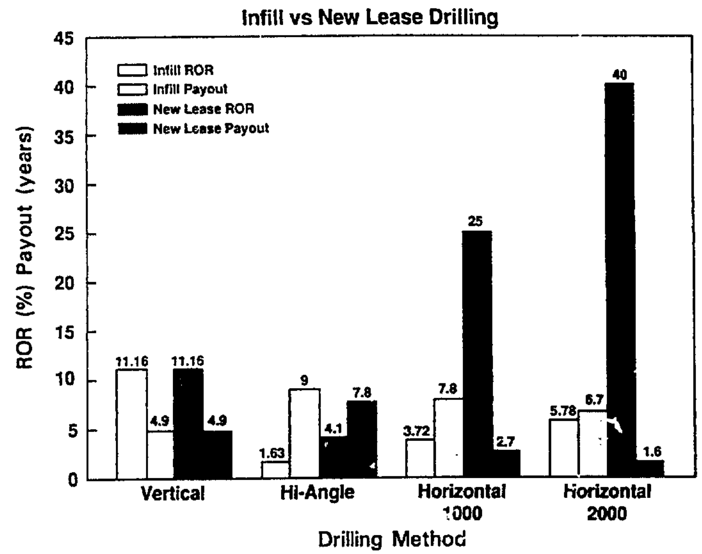

Figure 14 - Economic Analysis

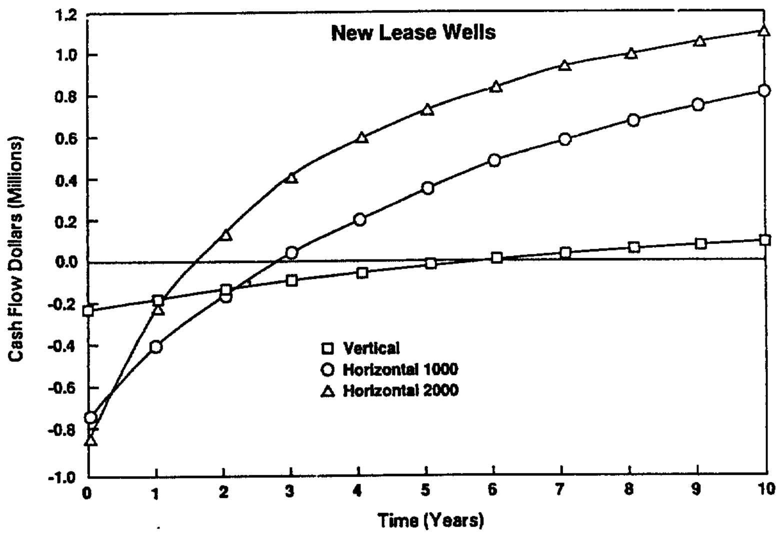

Figure 15 - Cumulative Cash Flow

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